EXHIBIT C

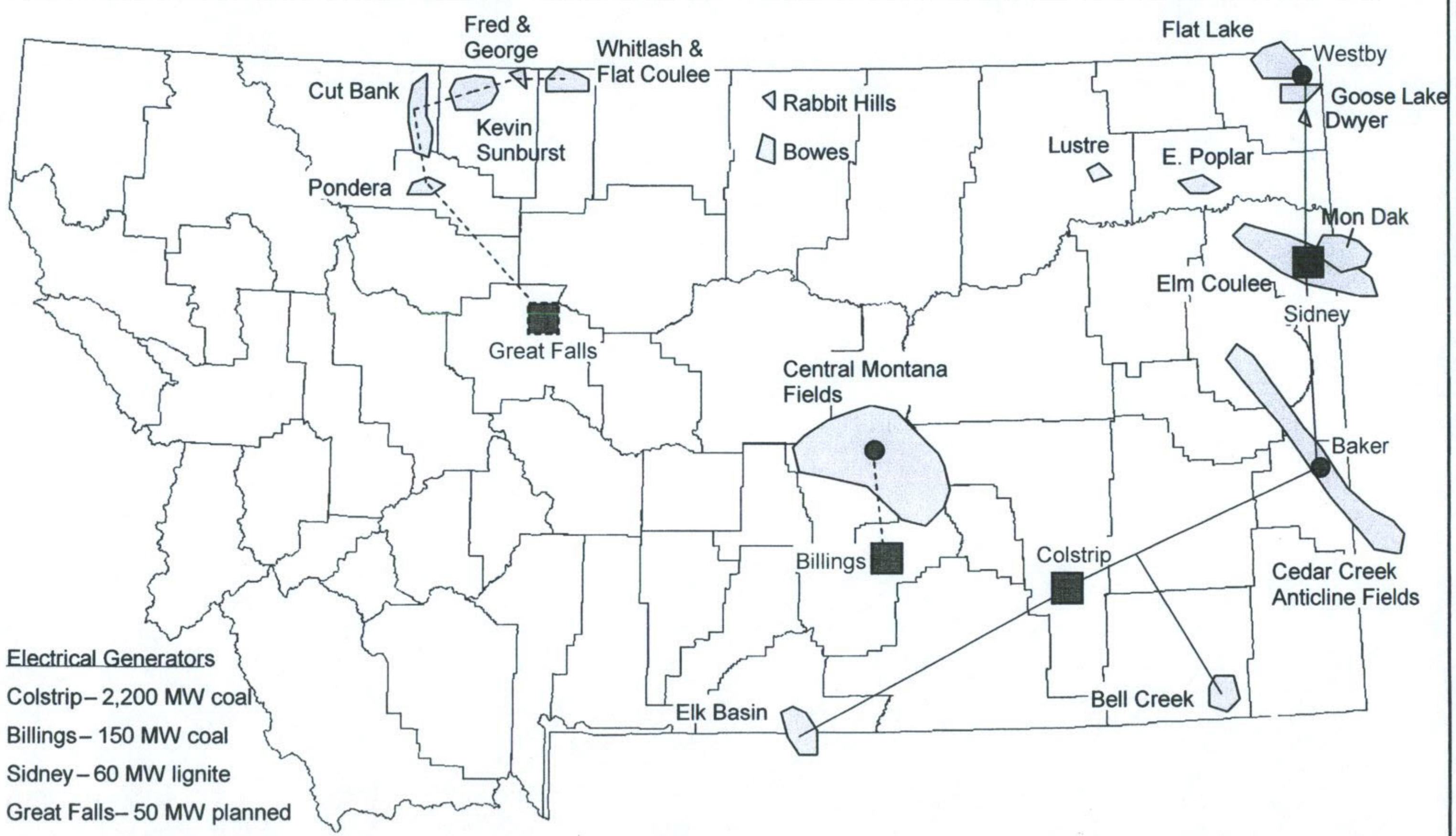
C

Exhibit C

Engineering Study of EOR Methods

Elm Coulee Field Bakken Reservoir
Richland County, MT

Montana Oil Producing Areas



<u>Electrical Generators</u>

Colstrip– 2,200 MW coal

Billings– 150 MW coal

Sidney– 60 MW lignite

Great Falls– 50 MW planned

EOR Potential of Bakken

- Current Elm Coulee Bakken will only recover ~10% of original oil.
- Remaining target residual oil of 2.07 billion bbls.
- Miscible CO_2 or natural gas flooding appear to be best alternative methods of EOR.
- No conclusive engineering has been done to determine best EOR methods and procedures to improve Bakken oil recovery.
- Estimated range of 230 to 460 million bbls of EOR Bakken oil.

Benefits of Engineering Study

- Basis for oil companies to pursue EOR.

- Satisfy initial concerns about range of costs and returns.
- Would promote pilot test, unitization, and field-wide EOR implementation.

- Bolster area production and economy.

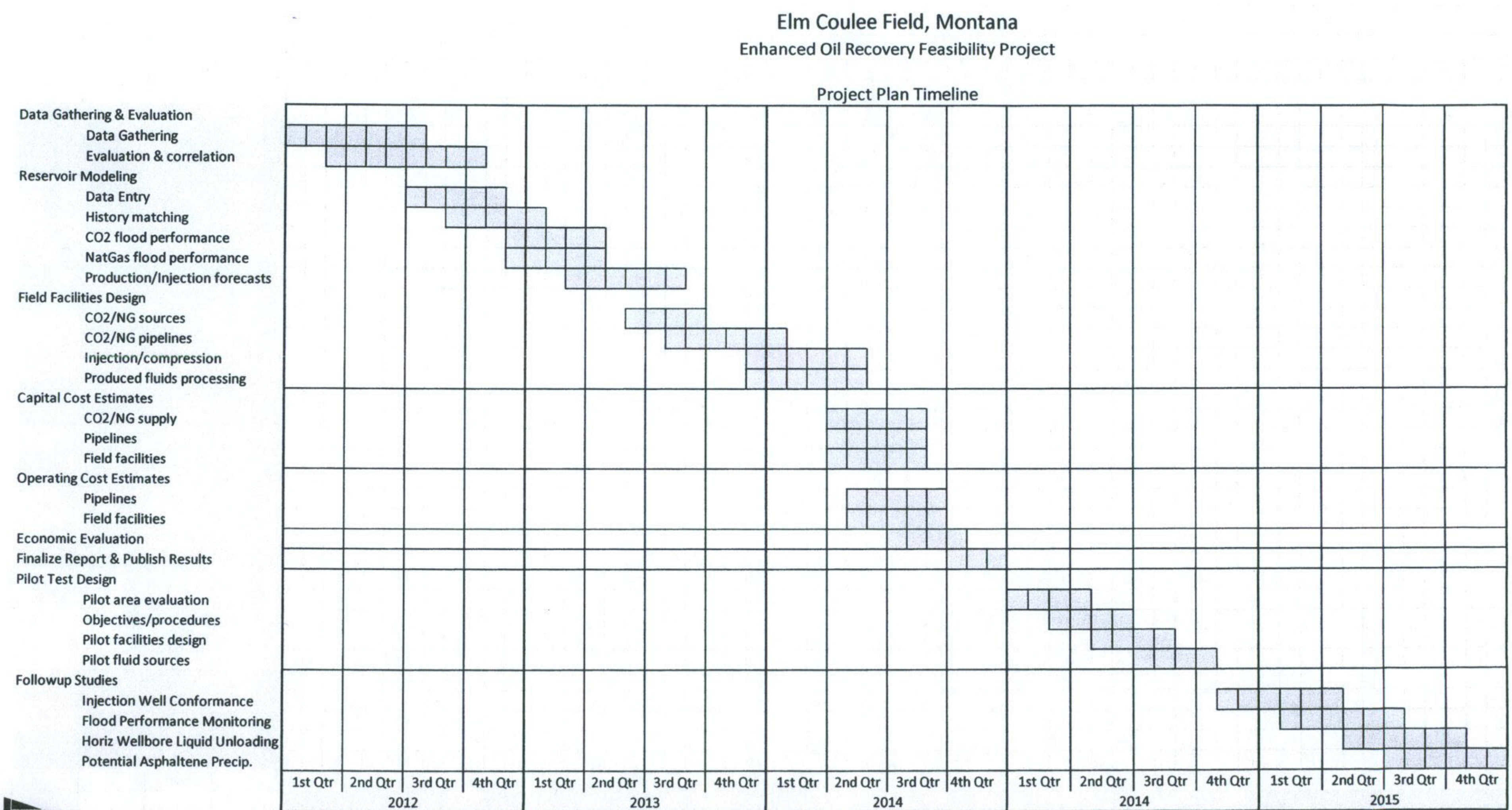
- Assist Montana Tech in providing specialized knowledge for important MT oil resource.

Five Year Project Budget

Start

Budget Items			Totals	2012	2013	2014	2015	2016
Salaries								
Faculty/Staff								
1 @ 60%			$ 300,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000
3 @ 25%			$ 133,300	$ 26,660	$ 26,660	$ 26,660	$ 26,660	$ 26,660
Graduate Students			$ 50,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Admin Support			$ 10,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000
Payroll Benefits @ 25%			$ 110,825	$ 22,165	$ 22,165	$ 22,165	$ 22,165	$ 22,165
		Subtotal	$ 604,125	$ 120,825	$ 120,825	$ 120,825	$ 120,825	$ 120,825
							$ -	$ -
Overhead Expenses @ 25%			$ 172,781	$ 34,556	$ 34,556	$ 34,556	$ 34,556	$ 34,556
Travel Expenses			$ 67,000	$ 13,400	$ 13,400	$ 13,400	$ 13,400	$ 13,400
Communications			$ 3,300	$ 660	$ 660	$ 660	$ 660	$ 660
Contracted Services			$ 16,700	$ 3,340	$ 3,340	$ 3,340	$ 3,340	$ 3,340
							$ -	$ -
							$ -	$ -
		Total	**$ 863,906**	**$ 172,781**	**$ 172,781**	**$ 172,781**	**$ 172,781**	**$ 172,781**

Project Timeline



Conclusions

- $864k to fund projects for five years.
  - Base study of $518k for three years
  - Pilot study of $173k in year four
  - Followup studies of $173k in year five

- Involve industry in acquiring data and communicating results.

- Could "jump-start" the initiation of EOR in a large oil resource area of Montana.

EXHIBIT D

Proposal to the
MONTANA BOARD OF OIL & GAS CONSERVATION

for

FUNDING FOR A FEASIBILITY STUDY FOR ENHANCED OIL RECOVERY FROM THE ELM COULEE FIELD

October 12, 2011

We are requesting financial assistance to conduct an engineering feasibility study to evaluate the benefits of using miscible gases to improve the recovery of oil from the Bakken reservoir in the Elm Coulee field, Richland County Montana. The requested assistance is a grant of $510,625 over a period of 3 years beginning in January 2012

The study is to be conducted by the Petroleum Engineering Department at Montana Tech. The principle investigators will be John Evans and Leo Heath. Other faculty, graduate students, and the computing resources of the Department will be utilized. The study will use information and data from industrial and public sources. A feasibility study, which compares the potential oil recovery by injecting various fluids into the reservoir, will be published. The report will include the geologic, engineering, and economic background that supports conclusions of the study

Urgency

A current estimate of primary oil recovery from Elm Coulee is 10 percent of the 2.3 billion barrels of original oil in place. Approximately one-half of the primary reserves will be recovered by the end of 2011, following 11 years of development and production. Roughly 50 years will be required to recover the remaining primary oil reserves at continually declining rates, beginning with today's 16% per year (Attachments 1 and 2).

The primary recovery mechanism is rock and fluid expansion above the oil bubble point pressure and solution gas drive below the bubble point. Pressures in parts of the reservoir have declined below the bubble point (Attachments 3 and 4). Water influx is present, but any benefit of additional recovery from water invasion is not apparent (Attachment 5). Enhanced oil recovery methods could improve recovery from the field by an additional 10 to 20 percent of the original oil in place. Enhanced recovery methods respond better when initiated before the reservoir is substantially depleted beyond the bubble point pressure.

We believe that an economical method for enhancing oil recovery at Elm Coulee will be found. The enormity of the resource compels us to determine this process. A successful EOR project at Elm Coulee will improve Montana's oil production and tax revenue base and add significantly to the economy of eastern Montana.

Complex Nature of the Reservoir

Elm Coulee is a relatively young field, which means that some aspects of the primary oil recovery mechanism are not yet fully understood. The reservoir has exceptionally low matrix permeability (0.05 to 0.5 md) and some areas of the reservoir are naturally fractured. Naturally fractured, low matrix permeability reservoirs developed with multiply fractured horizontal laterals present a difficult problem for enhanced oil recovery processes. The combined effect of the hydraulic fractures and naturally occurring fissures on the sweep efficiency of injected fluids will be a major uncertainty with any EOR project proposed for Elm Coulee. Most EOR projects are conducted from non-fractured, vertical injection wells.

Other factors could also limit the success of enhanced oil recovery and these must be recognized and addressed in the proposed study.

EOR Methods

Technical elements that are vital for a successful EOR project are good injectivity, displacement efficiency, and sweep efficiency. Waterflooding is questionable because high water viscosity will severely limit injection rates at pressures below the formation-fracturing gradient. Even if it did result in recovery improvements, the additional oil would be recovered at an extremely slow rate, meaning that any additional oil would be recovered at marginal rates over many decades.

Flooding with a vapor media, such as carbon dioxide (CO2), nitrogen (N2), natural gas (NG), or air, offers the best choice for EOR at Elm Coulee. Because of their low viscosity, reasonable gas injection rates are likely even though permeability is low. CO2, N2, and NG can become miscible with oil, which greatly improves displacement efficiency.

EOR by air injection results in in-situ combustion of the reservoir oil. Very high temperatures and gaseous by-products are created, which act to improve oil recovery. In-situ combustion is not practical because the fire front will probably move very rapidly from injection wells through indigenous fissures and man-made fractures to the horizontal producing wells. The extreme heat and corrosive by-products will destroy producing wells with very little, if any, additional oil recovery.

Use of N2 is prohibitive because it is expensive and it is very difficult to separate N2 from produced gases to obtain a saleable grade of gas. In addition, N2 has a higher miscibility pressure than CO2 or NG

This proposal therefore focuses on the remaining options: miscible flooding with CO2 or NG. The best injectant between CO2 and NG must be determined.

1. Advantages of CO2
    a. Miscible under multiple contacts
    b. Low viscosity – good injectivity
    c. Moderate density – less over-riding
    d. Must be handled at high pressure but is safe from the standpoint of explosions and fire
    e. High oil displacement efficiency
    f. Sequestered in oil reservoir at the end of EOR operations
2. Disadvantages of CO2
    a. No source is readily available
    b. Poor areal and vertical sweep efficiency
    c. Corrosive when mixed with salt water
    d. Is not a hydrocarbon, so gas handling and re-injection facilities are expensive
3. Advantages of natural gas
    a. Miscible under multiple contacts
    b. Low viscosity – good injectivity
    c. HIgh displacement efficiency at miscibility pressures
    v. Can be produced and sold at end of EOR operations
    e. Readily available into foreseeable future
    f. Relatively non-corrosive
    g. Is a hydrocarbon, so relatively low expenditures for gas handling and reinjection.
4. Disadvantages of natural gas
    a. Low density – more over-riding
    b. Poor areal and vertical sweep efficiency
    c. Must be handled at high pressure and is hazardous from the standpoint of explosions and fire

Past Experience

In 2005, Montana Tech began investigating Bakken EOR using CO2 with a scoping feasibility study undertaken to show the benefits of injecting and sequestering CO2 captured from the Colstrip coal-fired generating plant in oil reservoirs located at Elm Coulee and the Cedar Creek Anticline. Preliminary results from the studies suggested that such a project would be suitable for securing commercial sponsors and financing to proceed with the study. From 2007 through 2009, CO2 flooding potential at Elm Coulee and the Cut Bank fields was studied by graduate students at Montana Tech.

In 2009 a feasibility study was proposed by Montana Tech professors to evaluate the potential of: (1) retrofitting PPL's Colstrip power generation units with furnaces designed from clean coal technology to capture all CO_2 currently discharged at Colstrip, (2) delivering the CO_2 via a new pipeline system connecting Colstrip with oilfields near Baker, and Sidney, and (3) using the CO2 to enhance recovery from the oil fields along the Cedar Creek Anticline and Elm Coulee.

During the same time, however, Denbury Onshore company acquired the Cedar Anticline fields from Encore Acquisitions and began work to bring CO2 from Wyoming to southeast Montana. They plan to initiate CO2 flooding in the Bell Creek field followed by CO2 flooding in fields located along the Cedar Creek Anticline.

Denbury's plans for CO2 supply and EOR at the Cedar Creek Anticline fields have focused us now on the study of EOR at the Elm Coulee field. (If the study shows that CO2 flooding is favored over NG flooding, the possible use of CO2 captured from Colstrip as a source of CO2 could be revisited, especially if Denbury is using all of its available CO2 for their company EOR projects.)

Scope of New Studies

1. Reservoir Engineering

   Most of the data required for this study is available in files maintained by the Board of Oil and Gas Conservation. Operators in Elm Coulee will be requested to provide any non-routine data they have collected, especially results of special laboratory tests conducted on cores and reservoir fluids, fracture imaging logs, and pressure transient test data. We would also request the results of CO2 injectivity and huff-and-puff tests performed in the field. Access to such data will reduce costs, save time, and add essential background information to the study.

Historical production data will be analyzed to find best areas of the reservoir for a pilot EOR project and the initial stage for a fieldwide project.

A reservoir model suitable for simulating fluid flow mechanics when CO2 and natural gas (NG) are injected into the reservoir rock will be used. It will simulate the chemical and physical reactions taking place when the injectants react with the reservoir oil and water. Models will include immiscible and miscible conditions, diffusion of injectants into fracture blocks, and the effects of conformance control measures. Industry will be canvassed for advanced software that would improve study efficiency, provide more insight into the flow of fluids in fractured porous media, and increase confidence in the results.

The most important results of the reservoir-engineering segment of the study will be to

a. Predict the additional reservoirs and rate of additional oil recovery.
b. Estimate the amount and period over which CO2 and NG will be required. Estimate the amount and period that produced CO2 and NG must be captured and re-injected. Estimate the CO2 and NG injection rate and pressure for individual wells.
c. Delineate which existing production wells will be converted to injection wells and where new injectors and producers must be placed. Determine whether new wells should be horizontal or vertical.

2. Production, drilling, and facility engineering

Additional field development is usually necessary when an enhanced recovery project is installed. The need for additional wells will be investigated. New wells may be vertical or horizontal placed at locations to improve sweep efficiencies and increase overall injectivity. Liquid and gas handling facilities must be expanded to handle additional oil and gas production rates. CO2 requires the installation of corrosion resistant pipe, fittings, valves, etc. to mitigate problems associated with corrosion.

The major tasks in this part of the study will be to

a. Determine the equipment requirements for handling the additional oil, gas, and water production expected from CO2 and NG flooding, the equipment requirements for separating CO2 from produced hydrocarbon gas, and the compression requirements for re-injecting produced CO2 and NG.

b. Evaluate the logical methods for consolidating production facilities to improve performance and efficiency. Included will be installation of injection lines and protection of injection and production wells from corrosion problems, especially with CO_2.

c. Evaluate the potential for damaging asphaltene deposition from CO_2 and NG contact with the reservoir oil.

d. Estimate the cost of re-fitting the entire field for CO_2 and NG flooding and drilling and completion costs for new wells and recompletion of existing wells.

e. Estimate the cost of operating the EOR facility.

3. Economic evaluation

The comparative feasibility of using CO_2 or NG to enhance recovery from oilfields under various scenarios will be examined such as

a. The advantage of higher recovery factors by CO_2 flooding offset by the major disadvantage of the higher cost of modifying facilities for corrosion and the need to remove CO_2 from natural gas for re-injection.

b. The advantages of by NG flooding is the lower cost of converting facilities for processing and corrosion control of produced fluids and the recovery NG purchases. The major disadvantages of NG flooding are that the expected recovery will likely be lower and the initial cost of NG will be greater than CO_2.

The additional tax and royalty income to the Counties and the State from EOR will be forecasted together with an estimate of the additional employment fostered by an EOR project.

4. Pilot Flood

A pilot flood will most certainly be required to confirm projected reserves and to answer questions for which essential data is not available or questions that can only be answered by conducting experimental tests in the field. Essential engineering chores involving the pilot flood will include the best choice of the pilot site, the number of wells in the pilot, the amount of injectant used, and sufficient monitoring to insure that results will lead to an obvious selection of the best EOR option.

5. Other studies that may be necessary to complement the proposed study.

a. Search for methods of improving the conformance (vertical and horizontal sweep efficiency) when low viscosity, low density gases (CO_2 and NG) are injected into the Bakken reservoir at Elm Coulee.

b. Search for methods of improving the flow performance of multi-fractured horizontal wells under multiphase, high gas/oil ratio conditions. The evaluation of the best means of artificial lift to maximize recovery will comprise a large part of this work.

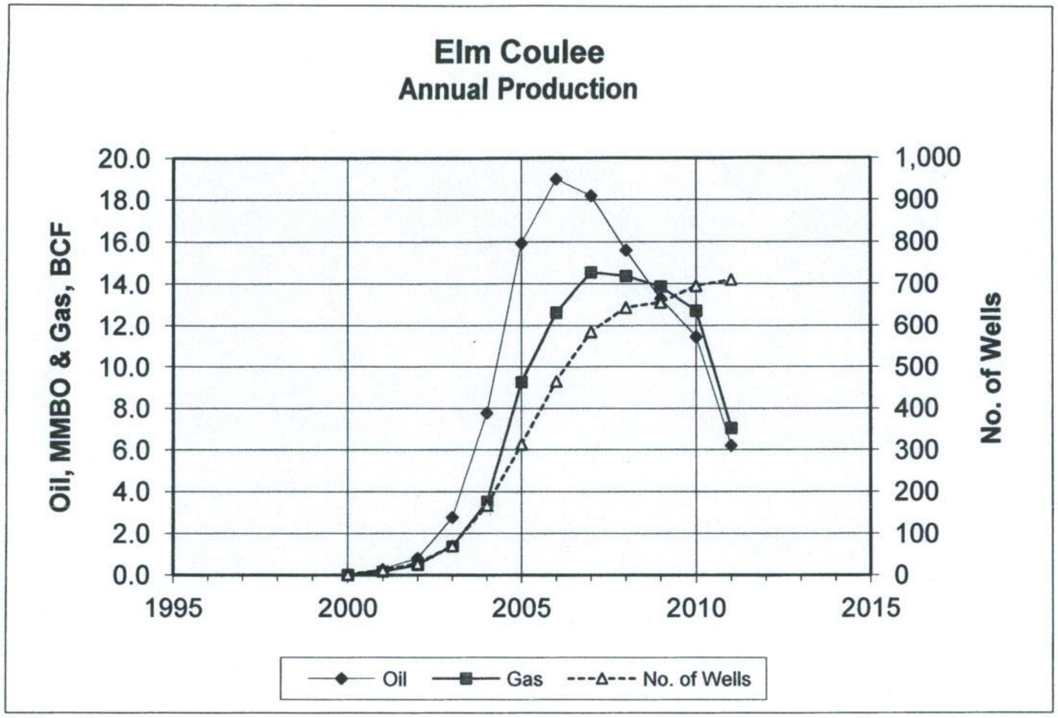
c. Determine whether asphaltene precipitation will be a major operating problem during a CO_2 flood.

More details regarding our proposed study are provided on Attachment 6.

Benefits

- Favorable results from the study could lead industry towards earlier implementation of an EOR project in Elm Coulee
- Increase of area construction and operating activity to stimulate local economy.
- Assist in sequestering CO_2.
- Prompt the evolution of clean-coal technology as a source of EOR-grade CO_2
- Increase tax and royalty revenues for the county and state
- Support a basic Montana industry with a basis for business growth opportunities

Attachment 1



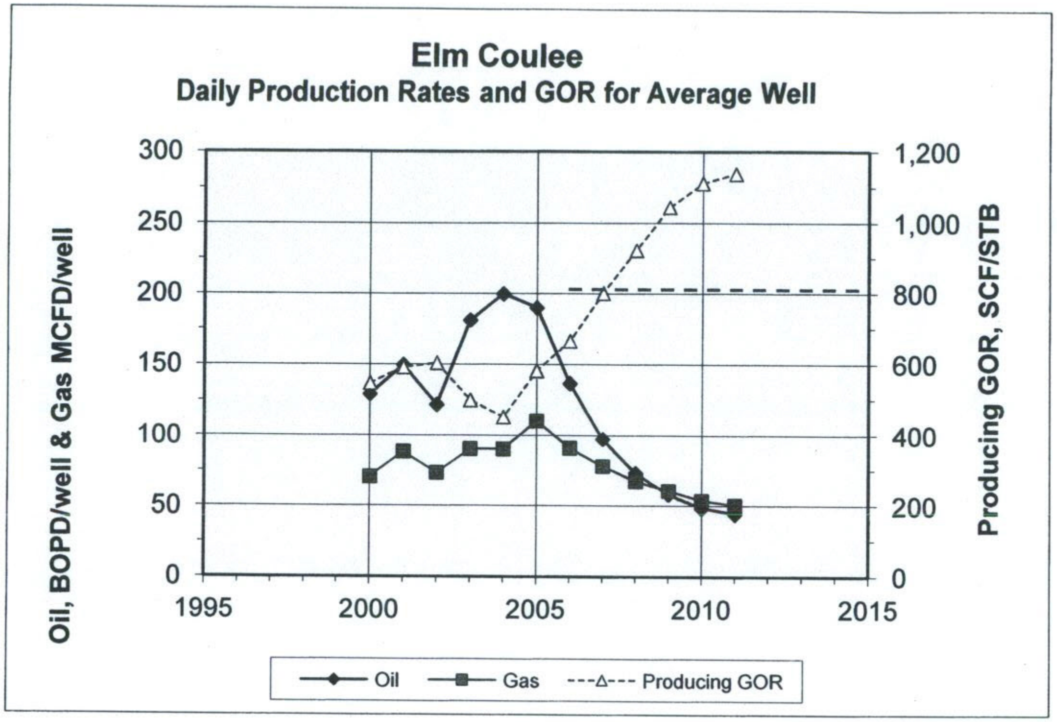
(Note, the 2011 data point includes only 8 months of production history.)

Production rates started declining in 2006 when approximately 460 wells were producing.

Approximately 250 new wells were drilled from 2006 to 2011, and decline rates were not arrested.

July 2011 Elm Coulee Annual Production
Source: Montana BOC

Attachment 2



The data in the above graph represents the combined production for older wells that have declined to low rates and new wells that that are still producing in the initial flush production stage. Older wells were probably not stimulated as efficiently as the newer wells.

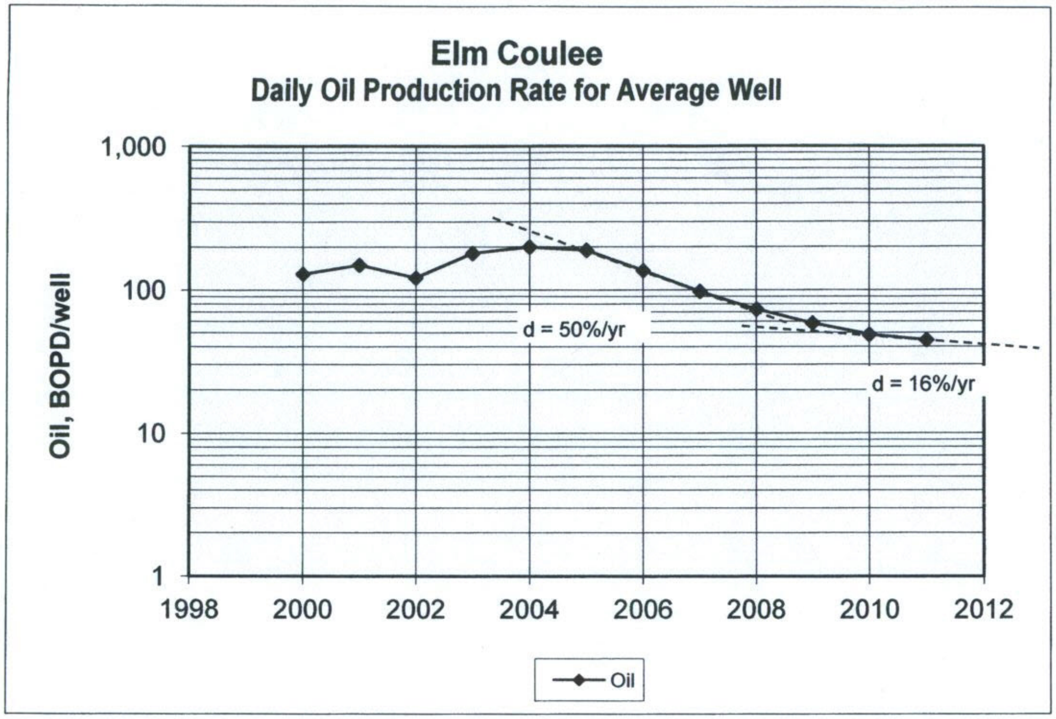
There is approximately 2800 feet of structural relief in the Elm Coulee reservoir. Initial reservoir pressure ranged from 4600 psi NW updip edge to 5000 psi at the deeper SE edge.

The density of the reservoir oil should be greater in the deeper, higher-pressure parts of the reservoir. The solution GOR will likely be higher in the shallower areas. The GOR data in the above chart represents oil from all reservoir depths. Since various sectors of the reservoir are subject to different degrees of depletion (i.e. the age of wells ranges from 11 to roughly one year), the producing GOR's will vary substantially across the reservoir.

The solution gas/oil ratio, based on single stage separation from one oil sample, was determined to be 807 SCF/STB at the bubble point pressure of 2958 psi. By comparing this value with producing GOR's starting in 2007, one can conclude that the reservoir pressure in some portions of the reservoir are below the bubble point.

July 2011 Elm Coulee Annual Production
Source: Montana BOC

Attachment 3



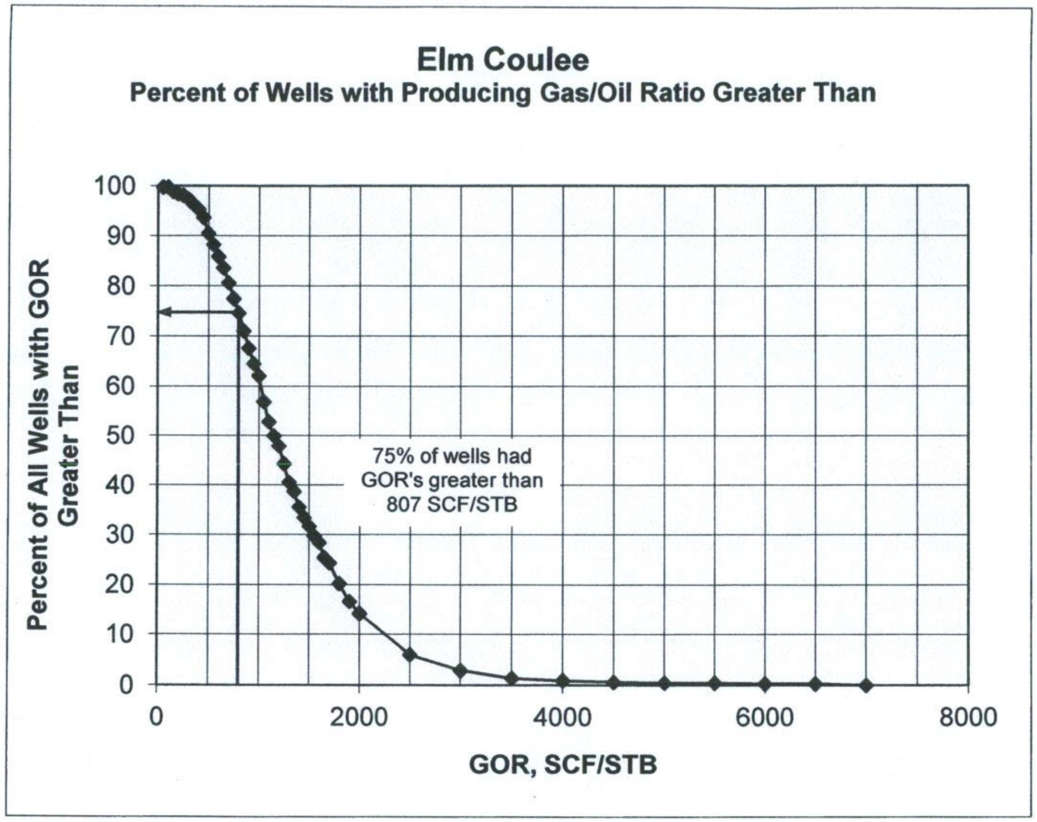
An average well is the composite of all old and new wells in the field. It is determined by dividing the annual fieldwide producing rate by the annual total number of producing-well days.

In 2004, the fieldwide production rates under primary rock and fluid expansion drive began to decline even though new wells were being completed. The decline rate was 50% per year from 2005 to 2008.

All individual well decline rates at Elm Coulee have a hyperbolic decline shape. As expected, the average well decline also has the hyperbolic decline shape. In 2011, the decline rate will be 16 %/year. The decline rate will continue to decrease in the future, as the above curve indicates.

July 2011 Elm Coulee Annual Production
Source: Montana BOC

Attachment 4

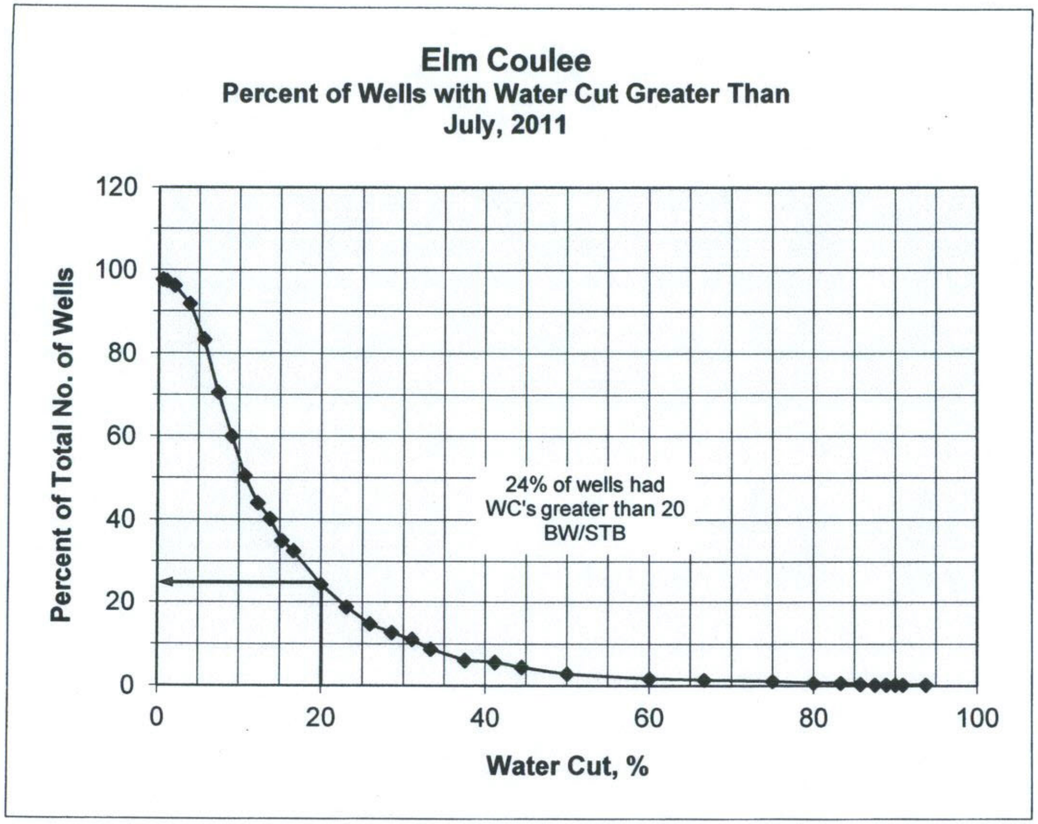


The data set contains 712 samples, i.e. wells in the field in July, 2011
Of these wells,

8 produced zero (0) oil and small amounts of gas and water.
18 no gas production reported
17 were shut-in.
669 were producing and included in statistic

July 2011 Elm Coulee Monthly Production
Source: Montana BOGC

Attachment 5



The data set contains 712 samples, i.e. wells in the field in July, 2011
Of these wells,
8 produced zero (0) oil and small amounts of gas and water.
17 were shut-in.
687 were producing and included in statistic

July 2011 Elm Coulee Monthly Production
Source: Montana BOGC

Attachment 6

Outline for the Engineering and Economic Study for

DETERMINING THE FEASIBILITY OF CO_2 OR NATURAL GAS FLOODING IN THE ELM COULEE FIELD

A. Study Preparation

1. Gather Data
    a. Completion reports from all wells
    b. Open hole logs from vertical wells
    c. Core and fluid property data
    d. Well test data
    e. Production data from all wells
    f. Field map showing location of facilities, flow lines, pipelines, etc.
    g. Description of facilities
    h. Request special data from Elm Coulee operators

2. Data preparation – build suitable files for statistical evaluation
    a. Completion data
        - Well locations
        - Operator
        - Date drilled
        - Length and azimuth of horizontal lateral
        - Type of completion (pre-perfed liner; cemented and perforated; liner with external casing packers, set, and perforated).
        - Stimulation [number of fracs, type of fracturing treatment (water, hybrid, gelled water)]

    b. Petrophysical data
        - Log data (analytical and digital) from vertical wells that penetrated the Bakken formation
        - Formation water resistivity
        - Matrix density, neutron, and sonic data
        - Routine and special core data
        - Reservoir fluid properties

    c. Production data
        - Monthly oil, gas, water, and time on
        - Cumulative oil, water, and gas vs. time
        - WOR, and GOR vs. time

3. Analyses of data
    a. Compute porosity, clay content, water saturation, and net pay thickness from well logs. Statistics from log porosity
    b. Statistics and correlations from core porosity and permeability and log porosity
    c. Compute decline rate parameters, future production rates vs. time, and EUR from production data
    d. Correlate completion data with production data, searching for meaningful trends that show improvement in completion efficiency

e. Compare operator, location, net pay, stimulation methods with production data to determine best completion practices and best producing areas of the reservoir

B. Reservoir Engineering

1. Reservoir Characterization – prepare maps necessary for simulation studies
   a. Net pay thickness isopach
   b. Iso-porosity
   c. Iso-permeability

2. Single-Well Studies - search for explanation for high productivity of multi-fractured horizontal wells than known data would predict, results to be used in reservoir simulation

3. Reservoir Simulation

   a. Determine necessary number of "township" size areas for the field for detailed reservoir studies
   b. History match production performance of each township
   c. Simulate CO2 flooding in each township area
   d. Simulate NG flooding in each township area
   e. Scale-up results from Step 3 to field-wide performance
   f. Scale-up results from Step 3 to field-wide performance (include blowdown of gas reserves)
   g. Determine injection and production well locations.
   h. Determine volumes of CO2 or NG needed, when CO2 and NG will be needed, how much CO2 and NG will be recycled.
   i. Determine whether WAG methods may be beneficial in improving sweep efficiency

C. Production, drilling, and facility engineering

1. "Design" the upgrade of field facilities for handling and processing of production from CO2 and NG flooding. Included in the designs are:
   a. Resizing separation equipment for additional oil, gas, and water
   b. Upgrading flowlines and wellheads for corrosion protection (CO2 flooding)
   c. Reconfigure collection system
   d. Centralizing production facilities
   e. Installation of injection lines
   f. Installation of amine sweeteners for CO2 separation
   g. Installation of gas processing for NGL recovery
   h. Compression for re-injection of CO2 or NG
   i. Equipment for injection conformance improvement

2. Drilling and completion – determine best practices for
   a. New injection wells (horizontal and vertical)
   b. New production wells

D. Economic evaluation

1. Cost estimation for capital expenditures, including new wells, well workovers, facility upgrading, compression, etc..
2. Incremental operating costs for
   a. CO_2 or NG
   b. Electricity and fuel
   c. Labor
   d. Chemicals
   e. Maintenance
3. Full cycle economics for the projects
4. Minimum CO_2 or NG hurdle price for project approval
5. Estimation of tax and royalty income to County and State

E. Pilot Project

A pilot project using the injectant selected as the best option between CO_2 and NG will be conducted. The purpose of the pilot project will be to prove the validity of the engineering, geological, and facility data and assumptions used in the feasibility study. The following items will be among the considerations given to the design of the pilot.

1. Location and size
2. No. of wells coupled with the use of existing wells and need for additional wells (injectors, producers, observation wells)
3. Additional facilities needed to handle production changes in the pilot area
4. Amount and source of injectant to be used
5. Paramters for monitoring the progress of the pilot flood
   a. Production improvement
   b. Injectivity
   c. Changes in in-situ fluid saturations
   d. Harmful changes in fluid characteristics (asphaltenes, paraffins)
   e. Recovery improvement

F.. Follow-up Studies

1. Source of Injectants
   a. CO_2
      - Denbury
      - PPL (Colstrip)
      - WBI (Sidney)
      - Northwestern (Billings)
      - Coal gasification plant (Beulah,North Dakota)
   b. Natural Gas
      - WBI gas storage at Cedar Creek Anticline (Baker)
      - Purchase gas from nearby gas transmission lines

2. Design of a Pilot Flood
   a. Purpose of pilot and required outcome to determine the type of pilot pattern
   b. Amount of fluid injectant
   c. Size and location
   d. Requirement for new producing wells in pilot area
   e. Observation wells
   f. Modification of existing facilities for pilot flood
   g. Monitoring methods
   h. Cost estimates

Montana Board of Oil and Gas Conservation
Summary of Bond Activity

EXHIBIT E

8/9/2011 Through 10/11/2011

Approved

Beartooth Energy, LLC Tallahassee FL		657 G4	Approved Amount: Purpose:	9/7/2011 $5,000.00 Single Well Bond
Surety Bond	$5,000.00	FIDELITY & DEPOSIT CO. OF MD		
Evolution Oil Group, LLC Vancouver BC		691 M1	Approved Amount: Purpose:	10/3/2011 $50,000.00 Multiple Well Bond
Certificate of Deposit	$50,000.00	FIRST INTERSTATE BANK		
Goertz, William and Beth Billings MT		686 D1	Approved Amount: Purpose:	8/24/2011 $5,000.00 Domestic Well Bond
Certificate of Deposit	$5,000.00	STOCKMAN BANK, BILLINGS		
Justice SWD, LLC Dagmar MT		690 T1	Approved Amount: Purpose:	9/23/2011 $10,000.00 UIC Single Well Bond
Certificate of Deposit	$10,000.00	MONTANA STATE BANK, PLENTYWOOD		
Kelly Oil and Gas LLC Roundup MT		645 M1	Approved Amount: Purpose:	10/4/2011 $50,000.00 Multiple Well Bond
Letter of Credit	$50,000.00	FIRST SECURITY BANK OF ROUNDUP		
Mountain View Energy, Inc. Cut Bank MT		344 T6	Approved Amount: Purpose:	8/30/2011 $10,000.00 UIC Single Well Bond
Certificate of Deposit	$10,000.00	Bank of Glacier County		
Northern Oil Production, Inc. Bozeman MT		5421 T5	Approved Amount: Purpose:	9/7/2011 $10,000.00 UIC Single Well Bond
Certificate of Deposit	$10,000.00	FIRST INTERSTATE BANK		
Northern Oil Production, Inc. Bozeman MT		5421 T4	Approved Amount: Purpose:	9/7/2011 $10,000.00 UIC Single Well Bond
Certificate of Deposit	$10,000.00	FIRST INTERSTATE BANK		
Petroshale Energy, LLC Henderson NV		689 M1	Approved Amount: Purpose:	9/19/2011 $50,000.00 Multiple Well Bond
Certificate of Deposit	$50,000.00	FIRST INTERSTATE BANK		
Sagebrush Resources II, LLC Highlands Ranch CO		692 G1	Approved Amount: Purpose:	10/4/2011 $10,000.00 Single Well Bond
Certificate of Deposit	$10,000.00	FIRST STATE BANK OF SHELBY		

Montana Board of Oil and Gas Conservation
Summary of Bond Activity

8/9/2011 Through 10/11/2011

Approved

SBG Sheridan Facility LLC Grand Forks ND		683 T1	Approved Amount: Purpose:	8/22/2011 $10,000.00 UIC Single Well Bond
	Certificate of Deposit	$10,000.00	FIRST INTERSTATE BANK	
Shadwell Resources Group, LLC Richmond TX		687 T1	Approved Amount: Purpose:	9/7/2011 $10,000.00 UIC Single Well Bond
	Certificate of Deposit	$10,000.00	Wells Fargo Bank, NA	
Vess Oil Corporation Wichita KS		684 M1	Approved Amount: Purpose:	8/23/2011 $50,000.00 Multiple Well Bond
	Certificate of Deposit	$50,000.00	FIRST INTERSTATE BANK	
Wind River Hydrocarbons, Inc. Englewood CO		682 G1	Approved Amount: Purpose:	8/9/2011 $10,000.00 Single Well Bond
	Certificate of Deposit	$10,000.00	Wells Fargo Bank, NA	
Zeiders Bros. Oil & Gas Company, L.L.C. Edmond OK		688 G1	Approved Amount: Purpose:	9/19/2011 $10,000.00 Single Well Bond
	Certificate of Deposit	$10,000.00	Wells Fargo Bank, NA	

Released

Black Hawk Resources, LLC Bowman ND		128 M2	Released Amount: Purpose:	9/9/2011 $50,000.00 Multiple Well Bond
	Letter of Credit	$50,000.00	BANK OF BAKER	
	Surety Bond	$25,000.00	FIREMEN'S FUND INSURANCE CO.	
	Surety Bond	$25,000.00	FIREMEN'S FUND INSURANCE CO.	
	Surety Bond	$50,000.00	FEDERAL INSURANCE COMPANY	
G/S Producing, Inc. Chester MT		2782 U1	Released Amount: Purpose:	8/15/2011 $5,000.00 UIC Limited Bond
	Letter of Credit	$10,000.00	HERITAGE BANK - CHESTER	
	Letter of Credit	$5,000.00	U.S. Bank National Association	
	Letter of Credit	$5,000.00	First Security Bank Fort Benton	
Kelly Oil and Gas LLC Roundup MT		645 G1	Released Amount: Purpose:	10/1/2011 $5,000.00 Single Well Bond
	Letter of Credit	$5,000.00	FIRST SECURITY BANK OF ROUNDUP	
Macum Energy Inc. Billings MT		4550 G10	Released Amount: Purpose:	9/19/2011 $5,000.00 Single Well Bond
	Certificate of Deposit	$5,000.00	FIRST INTERSTATE BANK	

Montana Board of Oil and Gas Conservation
Summary of Bond Activity

8/9/2011 Through 10/11/2011

Released

Nextraction Energy (US) Inc. Vancover BC		668 M1	Released Amount: Purpose:	9/12/2011 $50,000.00 Multiple Well Bond
Certificate of Deposit	$50,000.00	Wells Fargo Bank, NA		
Savant Resources LLC Denver CO		581 G1	Released Amount: Purpose:	9/12/2011 $5,000.00 Single Well Bond
Surety Bond	$5,000.00	U.S. Specialty Insurance Co.		
Ursa Resources Group, LLC Houston TX		643 M1	Released Amount: Purpose:	9/8/2011 $50,000.00 Multiple Well Bond
Certificate of Deposit	$50,000.00	FIRST INTERSTATE BANK		
Weststar Energy, Inc. Worland WY		8330 B1	Released Amount: Purpose:	10/11/2011 $10,000.00 Blanket Bond
Surety Bond	$10,000.00	RLI INSURANCE COMPANY		

Rider Approved

Earthstone Energy, Inc. Denver CO		647 U1	Rider Approved Amount: Purpose:	9/12/2011 $20,000.00 UIC Limited Bond
Surety Bond	$30,000.00	RLI INSURANCE COMPANY		
Surety Bond	$20,000.00	RLI INSURANCE COMPANY		
Provident Energy Of Montana, LLC Austin TX		199 M1	Rider Approved Amount: Purpose:	9/30/2011 $25,000.00 Multiple Well Bond
Surety Bond	$25,000.00	RLI INSURANCE COMPANY		

EXHIBIT F

FINANCIAL STATEMENT
As of 10/01/11
Percent of Year Elapsed: 25

OIL AND GAS DIVISION
FY12 Budget vs. Expenditures

		2012 Regulatory Budget	Expends	Expends % of Budget	2012 UIC Budget	Expends	Expends % of Budget	2012 TOTAL BUDGET	2012 TOTAL EXPENDS	Expends % of Budget
FTE		17.0			3.5			20.5		
Obj.										
1000	General PS	-						-		
1100	Salaries	1,075,334	168,515	0.16	185,181	33,546	0.24	1,322,355	213,544	0.16
1300	Other Comp		675	0.00	322	57	-			
1400	Benefits/Ins	-			61,518	10,751				
1600	Vacancy Savings				(9,884)			(9,884)		
2100	Contracted Svcs	2,281,225	13,402	0.01	66,135	2,086	0.03	2,347,360	15,488	0.01
2200	Supplies	53,019	11,735	0.22	9,526	1,908	0.20	62,545	13,643	0.22
2300	Communications	39,482	8,754	0.22	7,228	1,800	0.25	46,710	10,554	0.23
2400	Travel	32,092	5,379	0.17	6,612	558	0.08	38,704	5,936	0.15
2500	Rent	17,769	3,684	0.21	2,353	1,428	0.61	20,122	5,112	0.25
2600	Utilities	11,908	2,968	0.25	2,464	670	0.27	14,372	3,638	0.25
2700	Repair/Maint	9,722	1,340	0.14	2,896	457	0.16	12,618	1,797	0.14
2800	Other Expenses	28,857	268	0.01	16,909	468	0.03	45,766	736	0.02
3100	Equipment	35,575	-	0.00	12,500			48,075	-	
6000	Grants							-	-	
Total		3,584,983	216,719	0.06	363,760	53,728	0.15	3,948,743	270,448	0.07

FUNDING										
	State Special	1,819,114	216,719		256,209	53,728		3,841,192	270,448	
	Federal				107,551	-		107,551		
Total Funds		1,819,114	216,719	-	363,760	53,728	-	3,948,743	270,448	

FY10 Carryforward		
Org 2013		
start balance		122,991
less exp		(1,250)
current bal	-	121,741

REVENUE INTO STATE SPECIAL REVENUE ACCOUNT 10/01/11			
	FY12	FY11	Percentage FY12:FY11
Oil Production Tax	-	1,562,946	
Gas Production Tax	-	265,464	
Drilling Permit Fees	11,275	54,300	
UIC Permit Fees		208,650	
Enhanced Recovery Filing Fee		-	
Interest on Investments	4,560	40,332	
Insurance Proceeds		-	
Accomodations Tax Rebate		491	
Copies of Documents	2,640	7,496	
Miscellaneous Reimbursemts		25,300	
TOTALS	$ 18,475	$ 2,164,979	0.01

REVENUE INTO DAMAGE MITIGATION ACCOUNT as of 10/01/11	
	FY11
Transfer in from Orphan Share	0
RIT Interest	0
Bond Forfeitures	0
Interest on Investments	92
TOTAL	$ 92

REVENUE INTO GENERAL FUND FROM FINES as of 10/01/11	
	FY12
Brandon Oil	20
Kelly Oil & Gas LLC	10
Hofland, James D	20
Hofland, James D	80
Slohcin Inc.	10
Slawson Exploration Co	5,000
McOil Montana One LLC	120
Misc. Oil Co	10
Phoenix Energy Inc.	90
Mountain Pacific General	4,900
Justice Oilfield Water Service Inc	20
ECA Holdings LP	10
Coalridge Disposal & Petroleum	10
SBG Sheridan Facility	1,000
TOTAL	$ 11,300

BOND FORFEITURES Go into Damage Mitigation Account
0

INVESTMENT ACCOUNT BALANCES 10/01/11	
Oil & Gas ERA	3,154,102
Damage Mitigation	295,411

GRANT BALANCES - 10/01/11			
Name	*Authorized Amt*	*Expended*	*Balance*
2009 Northern	300,000	0	300,000
2009 Southern	300,000	0	300,000
2007 Tank Battery	304,847	166,048	138,799
TOTALS	$904,847	$166,048	$738,799

CONTRACT BALANCES - 10/01/11			
HydroSolutions - Tongue River Info Project	1,218,486	1,035,798	182,688
Automated Maintenance Services, Inc.	27,458	2,910	24,548
Agency Legal Services - Legal	60,000	4,959	55,041
Central Avenue Mall	400	400	0
ALL-LLC - FY11 Engineering & Database Maint.	20,000	0	20,000
Liquid Gold Well Service, Inc. - 09 Northern	165,000	0	165,000
Liquid Gold Well Service, Inc. - 09 Southern	165,000	0	165,000
C-Brewer - 07 Southern Tank Battery (og-cb-134)	215,000	166,048	48,952
TOTALS	1,871,344	1,210,115	661,229

Agency Legal Services Expenditures in FY12		
Case	Amt Spent	Last Svc Date
BOGC Duties	4,959	09/11
Total	4,959	

EXHIBIT G

TOTAL DISTRIBUTION BY COUNTY
Since Inception through Present
Qtr End Sept 2005 - Qtr End March 2011
Tperrigo 9/8/11

COUNTY	TOTAL RECEIVED
BIG HORN	$ 524,191.76
BLAINE	640,909.35
CARBON	268,956.51
CARTER	24,460.79
CHOUTEAU	58,616.36
CUSTER	2,826.60
DANIELS	907.01
DAWSON	265,214.39
FALLON	4,424,792.65
FERGUS	2,335.50
GARFIELD	7,742.78
GLACIER	306,163.91
GOLDEN VALLEY	4,820.61
HILL	506,160.39
LIBERTY	126,636.42
MCCONE	5,017.42
MUSSELSHELL	79,932.80
PARK	77.30
PETROLEUM	13,130.67
PHILLIPS	727,808.56
PONDERA	89,861.14
POWDER RIVER	212,401.00
PRAIRIE	48,621.60
RICHLAND	10,089,144.42
ROOSEVELT	780,596.09
ROSEBUD	159,264.51
SHERIDAN	900,728.09
STILLWATER	17,325.26
SWEET GRASS	1,826.66
TETON	31,933.51
TOOLE	389,042.01
VALLEY	118,657.01
WIBAUX	445,487.72
YELLOWSTONE	10,911.37
TOTALS:	$ 21,286,502.17

EXHIBIT H

Privilege and License Tax Distribution to Board
Since avoided to counties
From start to present
Qtr End Sept 2005 - Qtr end March 2011

Total Received 16,284,878

Oil 12,777,580
Gas 3,507,298

Privilege and License Tax Receipts

Qtr End	Oil	Gas	Rate
Sept 02	239,752	48,227	0.026 of 1%
Dec 02	244,878	69,231	
March 03	266,315	158,091	
June 03	205,217	139,338	
Sept 03	256,076	187,576	
Dec 03	276,512	155,673	
March 04	343,307	180,346	
June 04	542,882	243,903	
Sept 04	650,332	252,907	
Dec 04	758,533	325,086	
March 05	812,080	348,034	
June 05	944,955	367,483	
Sept 05	836,676	325,374	0.018 of 1%
Dec 05	830,779	467,313	
Mar 06	790,349	338,721	
June 06	952,886	253,299	
Sept 06	1,002,159	250,539	
Dec 06	402,849	134,283	0.009 of 1%
March 07	395,539	138,973	
June 07	504,186	142,206	
Sept 07	545,403	111,709	
Dec 07	621,658	145,822	
March 08	671,660	167,915	
June 08	835,815	196,055	
Sept 08	752,794	165,248	
Dec 08	327,542	103,434	
Mar 09	216,104	68,243	
June 09	331,478	53,962	
Sept 09	361,550	49,602	
Dec 09	387,369	73,785	
March 10	393,644	80,626	
June 10	375,765	61,171	
Sept 10	381,036	62,029	
Dec 10	412,499	61,638	
March 11	447,837	55,351	

EXHIBIT I
RECEIVED
OCT 1 1 2011
MONTANA BOARD OF OIL & GAS CONS. BILLINGS

BENSUN ENERGY

October 7th, 2011

Dear Board Members,

Because of the limited amount of time available at our public hearings to properly describe our case we would like to summarize some history and valuable evidence to show probably cause why the BN wells in Fallon County should not be plugged and abandoned.

Bensun Energy is making every effort to develop Fallon County leases involving the BN 11-11 and BN 12-11 wells. We have appeared at several hearings to show cause so not to be forced to plug and abandon the BN leases. The board has mentioned three years of dealing with us on this issue when actually it has only been 1 year and 9 months since Bensun Energy first acquired this lease from the Carvers in the winter month of December 2009.

At our last board meeting in August we expressed our frustration with not having a work over rig available to show maintenance repairs needed to get the BN 11-11 oil well pumping. This well has a tubing leak and this requires a work over rig to pull out 9000' of rods and tubing, repair hole in tubing and put well back on line. This is not a critical breakdown that determines if a well is capable of production. Prior to the tubing leak the well was producing 5-10 barrels of oil per day and 15 barrels water from the Red River formation. There is no evidence that the integrity of the BN 11-11 well is bad. When Bensun took over operations we had the well logs researched by petroleum engineers. It was discovered there is a high probability of greater oil production from the Mission Canyon zone which is above the Red River. Bensun submitted a sundry notice with intent to test the Mission Canyon. Before we can produce the well at all there needs to be a battery to pump the water and oil to.

The biggest issue with this lease was the location of the tank battery. There was no tank battery. The BN wells where once pipelined to a shared central location producing into shared tanks. When one of the wells was sold in 1998 under Crown Oil bankruptcy, the sale of that well retained the central battery facility. The once connected BN wells were disconnected and left with no production facilities to pump to. Ownership was transferred to Titan Oil.

BENSUNENERGY.COM P.O. BOX 415 SIDNEY, MT 59270 CONTACT: 406-480-1344/406-488-2688FX

In order to produce the BN wells, a new tank battery had to be constructed at a separate location. These wells have sat idle for years being operated by Titan Oil. In December of 2009, Bensun Energy and Frank Baxter acquired the BN leases from Titan.

It is one thing to get the tubing leak fixed but how do you produce a well with no tank battery? It was determined because of the wells remote location that a pipeline would need to be installed and a new tank battery constructed almost a mile away.

This project has been taken on by Bensun Energy and Frank Baxter in an area during the Bakken Boom. Contractors are booked with long waiting lists to fill and working on Major contracts is a priority. In between jobs, contractors have been able to get pieces of our project started. We have resorted to buying our own equipment and tools to help further our progress. Countless hours are being spent working on preparation and plumbing flow lines, electrical, setting tanks, cleaning up locations and repairing lands disrupted by pipeline installation.

Every week we call and email work over rig companies begging them to squeeze in our tubing leak job. Any day now we could get the call that a rig is available, it just hasn't happen yet. We've drove hundreds of miles to meet with contractors to try and persuade their services. Last week we got a call back from a wire line company from Williston, ND that was available to do a cement bond log on the BN 12-11. This test can determine how much cement bonding is currently behind injection zone needed for Salt water disposal well conversion. This test was completed on Monday, Oct 3rd at a cost of $8,500. We met them on location with a rented crane to assist. We are awaiting bonding log interpretation to determine results.

Bensun Energy and Frank Baxter continue pouring all of their time and financial resources now in excess of $250K into this project to include buying all surface equipment, 9000' of down hole rods & tubing, purchase 12,000' and installing a mile of pipeline to both wells, site clean ups, new location construction, wire line cement bond log and countless other expenses that have been adding up. This investment of time and resources needs to be considered as valuable progress to comply. It does not seem to be recognized by the board and only the fact that a rig has not repaired the tubing leak is recognized as lack of progress and mention of more fines.

The efforts and results that Bensun Energy and Frank Baxter have shown, continues to be evidence of probable cause not to plug and abandon the BN wells. We ask that you allow our efforts to continue without punishment for things out side of our control and recognize what we have done. Getting these wells online is our number one goal, without their timely completion, the financial investments and time sacrifices have no returns for anyone.

Respectfully yours,

Lance Benson & Frank Baxter

BENSUNENERGY.COM P.O. BOX 415 SIDNEY, MT 59270 CONTACT: 406-480-1344/406-488-2688FX

MONTANA BOARD OF OIL AND GAS CONSERVATION

POLICY: COMPLIANCE WITH BOARD ORDERS ON PRODUCTION AND INJECTION REPORTING

The Montana Board of Oil and Gas Conservation (BOGC) collects production and injection information from oil and gas producers and injection well operators. Such information, in the form specified by the BOGC, is to be supplied by the operator to the BOGC on a regular basis pursuant to BOGC administrative rules 36.22.1242 and 36.22.1415.

If the reports are more than 4 months delinquent an immediate administrative penalty of $50.00 plus $10.00 per delinquent lease-month and $10.00 per delinquent injection well-month will be assessed. A notice of the assessment will be served by mail on the operator, and the operator will be given 30 days from the date of the penalty assessment to comply with the administrative rules of the BOGC.

If at the end of the above 30 day period, the operator still remains delinquent, the penalty will double, and the matter will be placed on the next Board docket as a show cause hearing. A notice of the hearing will be sent to the operator. At the specified time the operator must appear and show cause as to why the operator has not complied with the BOGC administrative rules.

If compliance issues beyond delinquent reporting are discovered the automatic scheduling of a show cause hearing may be waived by the staff and the matter discussed with the Board at its next scheduled meeting.

If, prior to the show cause hearing scheduled under this policy, the staff of the BOGC has received the required reports, and the operator has paid the penalties owed, the show cause hearing will be vacated and the operator so notified.

If a show cause hearing is convened and the operator does not appear, the BOGC will impose additional penalties as authorized under §82-11-147 (1) (b). Penalties may include the suspension of authorization to produce until compliance is achieved.

This policy is adopted by the BOGC on April 1, 2009 pursuant to the authority given to the BOGC in §82-11-147 (1) (b); §82-11-149; and as prescribed in Hawley v. BOGC, 2000 MT 2, 297 Mont. 467, 993 P.2s 677 (2000). Modified XXXXX, X, 2011.

10/13/11 Proposed 2012 Hearing Schedule

EXHIBIT K

STATE OF MONTANA
INSURANCE DEDUCTIONS CALENDAR
2012

KEY	
PAYDAYS	○
PAY PERIOD ENDING	□
HOLIDAYS	◇

JANUARY

S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	JAN 13	14
15	16	17	18	19	20	21
22	23	24	25	26	JAN 27	28
29	30	31				

FEBRUARY

S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	~~9~~	FEB 10	11
12	13	14	15	16	17	18
19	20	21	22	23	FEB 24	25
26	27	28	29			

MARCH

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	MAR 9	10
11	12	13	14	15	16	17
18	19	20	21	22	MAR 23	24
25	26	27	28	~~29~~	30	31

APRIL

S	M	T	W	T	F	S
1	2	3	4	5	APR 6	7
8	9	10	11	12	13	14
15	16	17	18	19	APR 20	21
22	23	24	25	26	27	28
29	30					

Butte

MAY

S	M	T	W	T	F	S
		1	2	3	MAY 4	5
6	7	8	9	10	11	12
13	14	15	16	~~17~~	FREE 18	19
20	21	22	23	24	25	26
27	28	29	30	31		

JUNE

S	M	T	W	T	F	S
					MAY 1	2
3	4	5	6	7	8	9
10	11	12	13	14	JUN 15	16
17	18	19	20	21	22	23
24	25	26	27	28	JUN 29	30

JULY

S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	~~12~~	JUL 13	14
15	16	17	18	19	20	21
22	23	24	25	26	JUL 27	28
29	30	31				

AUGUST

S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	9	AUG 10	11
12	13	14	15	16	17	18
19	20	21	22	23	AUG 24	25
26	27	28	29	30	31	

SEPTEMBER

S	M	T	W	T	F	S
						1
2	3	4	5	6	SEP 7	8
9	10	11	12	~~13~~	14	15
16	17	18	19	20	SEP 21	22
23	24	25	26	27	28	29
30						

OCTOBER

S	M	T	W	T	F	S
	1	2	3	4	OCT 5	6
7	8	9	10	11	12	13
14	15	16	17	18	FREE 19	20
21	22	23	24	25	26	27
28	29	30	31			

NOVEMBER

S	M	T	W	T	F	S
				1	OCT 2	3
4	5	6	7	8	9	10
11	12	13	14	~~15~~	NOV 16	17
18	19	20	21	22	23	24
25	26	27	28	29	NOV 30	

DECEMBER

S	M	T	W	T	F	S
						1
2	3	4	5	6	7	8
9	10	11	12	13	DEC 14	15
16	17	18	19	20	21	22
23	24	25	26	27	DEC 28	29
30	31					

= hearings/business mtgs ○ = ads must be published by X = filing deadline